

# **AMBIENT AIR QUALITY IMPACT REPORT**

## **(NSR 4-1-3, AZP 04-01)**

This document serves as the statement of basis and fact sheet required by 40 CFR 124.7 and 124.8. This document sets forth the legal and factual basis for the permit conditions and provides references to applicable statutory or regulatory provisions, including provisions under 40 CFR 52.21. This document is intended for use by all parties interested in the permit.

### **I. APPLICANT**

Sithe Global Power, LLC  
Desert Rock Energy Project  
Three Riverway, Suite 1100  
Houston, TX 77056

### **II. PROJECT LOCATION**

Sithe Global Power, LLC (“Sithe” or “applicant”), under a development agreement with the Navajo Nation’s Diné Power Authority, is proposing to construct a 1,500 megawatt (“MW”) mine-mouth, coal-fired power plant (“Facility” or “DREF”). The Facility will be located in the Northeastern Area of the Navajo Nation adjacent to Navajo Nation coal reserves at a mine operated by BHP Billiton. Sithe submitted an application for a Prevention of Significant Deterioration (“PSD”) permit to allow construction and operation of the coal-fired, nominal 1500 MW Facility on the Navajo Indian Reservation. The project is generally called the Desert Rock Energy Facility (“DREF”). The proposed 580 acre site is located approximately 25 miles southwest of Farmington, New Mexico.

The proposed DREF is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO<sub>2</sub>), sulfur dioxide (SO<sub>2</sub>), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM<sub>10</sub>), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NO<sub>x</sub>)). For purposes of this PSD permit and analysis, EPA will refer to NO<sub>x</sub>, which is functionally equivalent to NO<sub>2</sub>, for both pollutants. The Facility’s surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site.

### **III. PROJECT DESCRIPTION**

The proposed PSD permit, if finalized after EPA receives and considers significant comments from the public, will allow Sithe to construct two supercritical pulverized coal fired boilers designed for a total nominal generation capacity of 1,500 MW (gross). Each of the two units will be 750 MW (gross) and 683 MW (net). Sithe’s Facility will use a

once through, supercritical steam cycle and other design features that will enable this Facility to achieve a net efficiency greater than 40% based on the lower heating value of the fuel. Sithe will install and operate Best Available Control Technology (BACT) emission controls to minimize the Facility's emissions of regulated air pollutants. Sithe's Facility will minimize its water consumption by using a Heller system, dry natural draft cooling tower. The Facility's solid wastes produced by combustion of the coal and the air pollution control system will be returned to the mine.

### **Pulverized Coal-fired Boilers**

The proposed PSD permit, if finalized, will allow Sithe to construct two supercritical pulverized coal fired boilers designed for a total nominal generation capacity of 1,500 MW (gross) divided into two units of 750 MW (gross) and 683 MW (net) each. Each boiler will have a heat input capacity of approximately 6,800 MMBTU/hr (extreme maximum) and will burn up to 382 tons/hour of coal. In the supercritical cycle, each boiler will produce steam at 3,626 psi and 1,112°F at a rate of 4,636,000 lb/hour. The boilers will feed the high-pressure steam through a steam turbine generator to produce electricity and then to a direct contact jet condenser.

The proposed PSD permit's BACT air pollution controls for Sithe's supercritical pulverized coal-fired boilers consist of the following:

- Low-NO<sub>x</sub> burners and selective catalytic reduction (SCR) to reduce NO<sub>x</sub> emissions;

- Low sulfur coal, hydrated lime injection before a fabric filter, and wet limestone flue gas desulfurisation to reduce SO<sub>2</sub> emissions;

- Hydrated lime injection before a fabric filter, and wet limestone flue gas desulfurisation to reduce acid gas emissions including sulfuric acid mist;

- A fabric filter to reduce particulate emissions; and

- Good combustion controls to reduce CO and VOC emissions.

### **Auxiliary Boilers**

The proposed PSD permit, if finalized, will also allow Sithe to construct and operate three auxiliary steam generators to provide auxiliary steam during startup and shutdown of the main steam generator. Sithe will use auxiliary steam generators that are fire-tube/smoke-tube type (package boilers, shell type). Each auxiliary steam generator will have a heat input capacity of 86.4 MMBTU/hour. Sithe will reduce emissions from these units by only burning low sulfur (0.05% sulfur) distillate oil, operating Low-NO<sub>x</sub>

burners, practicing good combustion, and limiting operation to an average of 1,650 hours/year for the three boilers (equivalent to a total maximum annual fuel use in the three boilers of 142,560 MMBTU/year at full load operation).

### **Coal Handling**

As a mine mouth facility, Sithe will burn only the low sulfur, blended coal from the Navajo Nation mine operated by BHP Billiton. The coal will be delivered to the Facility by an enclosed conveyor system. Sithe will build a passive or inactive coal pile on the site for emergency purposes. Normal preparation and storage will be handled by BHP Billiton at the mine site. The conveyor from the Navajo Nation/BHP Billiton mine will move the coal through a series of enclosed transfer houses where the coal will drop onto conveyors for transport to bunkers provided for each boiler. From the bunkers, Sithe will feed the coal through pulverisers to the boilers. The Sithe Facility on-site coal piles will be covered or sealed to prevent emissions and spontaneous combustion. All of the conveyors that Sithe will operate will be totally enclosed to prevent emissions. The proposed PSD permit, if finalized, will require Sithe to operate dust suppression, enclosures, or baghouses to reduce emissions from material transfer points and the coal bunkers.

### **Cooling Towers**

The PSD permit, if finalized, will require Sithe to install and operate a direct contact jet condenser with a Heller dry cooling tower system. In this cooling system, the process steam from the steam turbine is fed to the condenser and condensed by direct cooling with the cooling water coming from the cooling cycle. The blended cooling water and condensate are collected in the hot-well and extracted by circulating water pumps. Approximately 2% of this flow – corresponding to the steam condensed – is fed to the boiler feed water system by condensate pumps. The major part of the flow is returned to the cooling tower for recooling. The cooling duty is performed by the cooling deltas, divided into parallel sectors, where cooling air flow is induced by a natural draft dry cooling tower. Sithe has applied to use, and the PSD permit is proposing to require, the Heller-type hybrid cooling tower to minimize water consumption. When the ambient temperature is below 80°F, the cooling tower will operate like a natural draft dry cooling tower. When the temperature exceeds 80°F, the Facility has the option of applying water oversprays on the heating surfaces inside of the cooling tower to provide additional cooling. This type of cooling tower does not emit any particulate matter or other pollutants.

### **Ash Handling**

Sithe will reduce emissions of fly ash by collecting the fly ash in the main fabric filter. The pulverized coal-fired boilers will also generate bottom ash. Fly ash and bottom ash

will be mixed in an ash silo. The proposed PSD permit, if finalized, will require any particulate matter emissions from the ash silo to be reduced by a fabric filter. Gypsum, with a water content in the 10% to 20% range, will be generated by the wet flue gas desulfurisation system. The gypsum fly ash and bottom ash will be mixed together and then transported back to the mine by an enclosed conveyor.

#### **IV. EMISSIONS FROM THE PROPOSED PROJECT**

The proposed Facility's estimated maximum annual potential emissions are summarized in Table 1 and are based on vendors' data, Sithe's design criteria, EPA emission factors from AP-42, and established emission calculation procedures. The estimated maximum annual potential emissions include emissions from the two supercritical pulverized coal boilers, the three auxiliary boilers, the emergency generators, the fire pumps, and materials handling. The estimated maximum annual potential emissions assume a 95% annual capacity factor at full load and include emissions from an anticipated 60 startups per year, with an average of 30 startups per boiler (4 cold, 10 warm and 16 hot). The Facility's startup and shutdown operations will not result in any excess daily or annual emissions compared to normal continuous operation. EPA has determined that Sithe's 95% capacity factor assumption and estimate of 60 startups per year is conservative, which means these assumptions are likely to lead to estimating higher potential emissions than the Facility will actually emit.

#### **V. APPLICABILITY OF THE PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATIONS**

The PSD regulations define a "major stationary source" as any source type belonging to a list of 28 source categories which emits or has the "potential to emit" 100 tons per year (tpy) or more of any pollutant regulated under the Clean Air Act, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tpy. 40 CFR 52.21(b)(1). Sithe has applied to construct a fossil fuel-fired steam electric plant of more than 250 MMBTU/hr heat input. It is, therefore, one of the 28 source categories specified in EPA regulations and the 100 tpy threshold applies for purposes of PSD applicability. The proposed Facility has the potential to emit over 100 tpy and is a major stationary source for all regulated pollutants except lead, fluorides and sulfuric acid mist.

Under the PSD regulations, a significant emissions increase is defined as an increase in emissions greater than the threshold prescribed for any pollutant subject to the regulation. 40 CFR 52.21(a)(1)(d). The significance thresholds prescribed by the PSD regulations at 40 CFR 52.21(b)(23) for lead, fluorides and sulfuric acid mist are listed in Table 2.

**Table 1**  
**Estimated Maximum Annual Potential Emissions**

<b>Pollutant</b>	<b>PC Boilers (tpy)</b>	<b>Auxiliary Boilers (tpy)</b>	<b>Emergency Generators (tpy)</b>	<b>Fire Water Pumps (tpy)</b>	<b>Material Handling (tpy)</b>	<b>Project Estimated Emissions</b>
NO <sub>x</sub>	3,315	7.13	2.26	0.41	n/a	3,325
CO	5,526	2.55	0.17	0.031	n/a	5,529
VOC	166	0.17	0.11	0.019	n/a	166
SO <sub>2</sub>	3,315	3.61	0.068	0.012	n/a	3,319
PM	553	1.02	0.083	0.015	16.1	570
PM <sub>10</sub>	1,105	1.68	0.077	0.014	12.9	1,120
Lead	11.1	0.00064	0.00012	0.0000022	n/a	11.1
Fluorides	13.3	neg	neg	neg	neg	13.3
H <sub>2</sub> SO <sub>4</sub>	221	0.062	0.002	0.0004	n/a	221
Mercury	0.057	0.000071	neg	neg	n/a	0.057

Note: 1. tpy - tons per year  
2. PM is defined as filterable particulate matter as measured by EPA Method 5.  
3. PM<sub>10</sub> is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub>.

PSD review applies to all pollutants that exceed the major stationary source threshold (100 tpy) or that exceed the significance thresholds for which the applicable federal National Ambient Air Quality Standards (NAAQS) have not been exceeded (attainment areas), or areas where the status of the area is uncertain (unclassified). The proposed Facility will be located in an area in the New Mexico Air Quality Control Region, which currently has a designation of attainment for all pollutants.

**Table 2**  
**Comparison of the Project Annual Emissions to the PSD Thresholds**

Pollutant	PSD Significance Level (tpy)	Project Emissions (tpy)
CO	100	5,529
NO <sub>x</sub>	40	3,315
SO <sub>2</sub>	40	3,315
TSP/PM	25	570
PM <sub>10</sub>	15	1,120
Ozone (VOC)	40	166
Lead	0.6	11.1
Fluorides	3	13.3
Sulfuric Acid Mist (H <sub>2</sub> SO <sub>4</sub> )	7	221

The estimated maximum annual potential emissions profile in Table 2 shows that the Facility is a major stationary source because its potential to emit exceeds 100 tpy for NO<sub>x</sub>, CO, SO<sub>2</sub>, PM, PM<sub>10</sub> and VOC. Table 2 also shows that the Facility's potential to emit lead, fluorides and sulfuric acid mist exceeds the significance thresholds. Therefore, all of these pollutants are subject to PSD review and must satisfy the following requirements:

1. Application of Best Available Control Technology (BACT);
2. Analysis of ambient air quality impacts from the project;
3. Analysis of air quality and visibility impacts on Class I areas; and
4. Analysis of impacts on soils and vegetation.

#### **VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)**

Section 169(3) of the Clean Air Act (CAA) defines BACT as follows:

The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act emitted from or which results from any major emitting facility.

The permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, makes a BACT determination through application of processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of BACT result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 (NSPS) or 7412 (NESHAP) of the Clean Air Act.

For attainment pollutants being regulated in a PSD permit, EPA evaluates emissions control requirements through a “top-down” BACT determination, which is described in EPA’s New Source Review Workshop Manual, Draft October 1990 (“PSD Manual”), page B-6. The top-down approach to the BACT review process involves identifying all demonstrated and potentially applicable control technology alternatives. PSD Manual, page B.11. EPA would typically review information in EPA’s BACT/LAER (Lowest Achievable Emission Rate) Clearinghouse, federal/state/local new source review permits, technical journals and other such sources. PSD Manual, page B.11. After broadly identifying potential control technology alternatives, EPA can eliminate any control alternatives that are not technically feasible because the alternative is either not available or not applicable. PSD Manual, page B.17. Next, EPA ranks each technically feasible control alternative to establish a hierarchy. PSD Manual, page B. 22. In the next step, the process either “validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top candidate is inappropriate as BACT.” PSD Manual, page B. 26. If the PSD applicant, Sithe in this instance, accepts the top (most stringent) control technology alternative as BACT, and that control alternative is not eliminated based on collateral environmental impacts, then the BACT analysis is complete and the top control technology alternative is selected. PSD Manual, page B.26. The top-down BACT analysis is a case-by-case exercise for the particular source under evaluation. In summary, the five steps involved in a top-down BACT evaluation are:

1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
2. Eliminate technically infeasible technology options;
3. Rank remaining control technologies by control effectiveness;
4. Evaluate most effective control alternative and document results; if top option is not selected as BACT, evaluate next most effective control option; and
5. Select BACT, which will be the most effective practical option not rejected based on energy, environmental, and economic impacts.

Sithe provided BACT analyses for NO<sub>x</sub>, CO, PM<sub>10</sub>, SO<sub>2</sub>, VOC, lead, hydrogen fluorides, and sulfuric acid mist and EPA independently evaluated the information Sithe submitted. The analysis and our evaluation for each pollutant is presented below.

## A. Nitrogen Oxides (NO<sub>x</sub>)/Nitrogen Dioxide

### 1. Pulverized Coal-Fired Boilers

NO<sub>x</sub> is formed during the combustion of fossil fuels, including coal, and is generally classified as either thermal NO<sub>x</sub> or fuel NO<sub>x</sub>. Thermal NO<sub>x</sub> is formed when elemental nitrogen reacts with oxygen in the combustion air within the high temperature environment of the furnace. The rate of formation of thermal NO<sub>x</sub> is a function of residence time and free oxygen, and is exponential with peak flame temperature. Fuel NO<sub>x</sub> is generated when nitrogen contained in the coal itself is oxidized. The rate of formation of fuel NO<sub>x</sub> is primarily a function of fuel bound nitrogen content of the coal but is also affected by fuel air mixing.

NO<sub>x</sub> emissions can be reduced using either combustion controls (i.e., staged combustion techniques such as Low-NO<sub>x</sub> burners (LNB), flue gas recirculation (FGR), overfire air (OFA), natural gas reburn, or flue gas treatment including selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR).

In accordance with the top-down BACT process, Sithe's PSD application first identified all of the potentially available control technologies for pulverized coal fired boilers, eliminated technically infeasible options, and then ranked the remaining control technologies, beginning with the technologies that will result in the most stringent control and the lowest emissions. EPA agrees that Sithe considered all of the potentially available controls, as shown below in Table 3, for pulverized coal-fired boilers. They include:

**Table 3**  
**NO<sub>x</sub> Control Technologies for Pulverized Coal Boilers**

Pulverized Coal Control Technologies	Control Efficiency Range (% Removal)	Typical Emission Rate (lb/MMBTU)
SCR and Low-NO <sub>x</sub> Burners	80 - 90	0.06 - 0.15
SNCR	40 - 60	0.2 - 0.3
Staged Combustion and Low-NO <sub>x</sub> Burners	30 - 50	0.15 - 0.5
Gas Reburn	40 - 60	0.15 - 0.3



## Selective Catalytic Reduction

SCR is a process that involves post-combustion removal of NO<sub>x</sub> from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO<sub>x</sub> decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system. The SCR reactor with necessary inlet and outlet duct work will be located downstream of the economizer and upstream of the air heater and the particulate control system. From the economizer outlet, the flue gas will first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas will then flow through the catalyst bed and exit to the air heater.

The SCR system for a pulverized coal boiler typically utilizes a fixed bed catalyst in a vertical downflow multi-stage reactor. The reactor will include a seal system to prevent gas from bypassing the catalyst bed. Access openings for catalyst loading/removal and periodic internal inspection will be provided. The reactor will contain multiple stages of catalyst with room for loading a future stage. For each stage, a soot blowing system will be provided. Each stage will be equipped with a platform with monorails and hoists to accommodate catalyst loading and unloading.

Reduction catalysts are divided into two groups: base metal (lower temperature, primarily vanadium, platinum or titanium) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO<sub>x</sub> ratio, and optimum oxygen concentration. A disadvantage common to base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but have been shown to also have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of ammonia to either nitrogen oxides (thereby actually increasing NO<sub>x</sub> emissions) or ammonium nitrate.

Optimum operating temperature for a vanadium-titanium catalyst system has been shown to be in the range of 550° to 800°F, which is significantly higher than for

platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when continuously operating at temperatures above this range. Consequently, operating above the maximum temperature for the catalyst system again results in the oxidation of ammonia to either nitrogen oxides (increasing NO<sub>x</sub> emissions) or ammonium nitrate.

Sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide to sulfur trioxide (SO<sub>3</sub>), which combines with water to form sulfuric acid. At typical SCR operating temperatures, SO<sub>3</sub> and sulfuric acid react with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled and can lead to increased uncontrolled emissions of PM<sub>10</sub> entering the particulate collector. Fouling may eventually lead to decreased NO<sub>x</sub> reduction performance, increased system pressure drop over time and decreased heat transfer efficiencies.

The SCR process is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a limited lifetime to very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 10 ppmvd of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO<sub>x</sub> reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which conversely results in ammonia slip. Thus an emissions trade-off between NO<sub>x</sub> and ammonia may occur in high NO<sub>x</sub> reduction applications.

The potential environmental impacts associated with the use of SCR include:

- Unreacted ammonia would be emitted to the atmosphere (ammonia slip).
- Ammonium salts would increase loading to the particulate collection stage as PM<sub>10</sub> (and PM<sub>2.5</sub>).
- Safety issues and Risk Management Planning may be required relative to the transportation, handling, and storage of ammonia (aqueous or anhydrous).

## Selective Non-Catalytic Reduction

SNCR has been applied to a number of different types of combustion sources, including petroleum heaters, utility and industrial boilers fired with natural gas and oil, as well as PC boilers and to coal-fired Circulating Fluidized Bed (CFB) boilers.

The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between  $\text{NO}_x$  in the flue gas and either injected  $\text{NH}_3$  or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the  $\text{NO}_x$  reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of  $\text{NO}_x$ . Consequently, the SNCR process operates at higher temperatures than the SCR process.

Critical to the successful reduction of  $\text{NO}_x$  with SNCR is the temperature of the flue gas at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 - 1,900°F; for the urea injection process the nominal temperature range is 1,600 - 2,100°F. Also critical to effective application of these processes are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia (or one-half mole of urea) will react with one mole of  $\text{NO}_x$ , forming elemental nitrogen and water. In reality, not all the injected reagent will react due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting a large amount of excess reagent and essentially achieving low  $\text{NO}_x$  emissions at the expense of emissions of unreacted reagent, referred to as ammonia slip. These emissions represent an adverse environmental impact and can lead to formation of ammonium salts and may contribute to regional haze as a precursor to  $\text{PM}_{2.5}$ . Thus, for a given boiler configuration, there is a limit on the degree of  $\text{NO}_x$  reduction which can be achieved with SNCR while maintaining acceptable levels of ammonia slip.

Pulverized coal-fired units have a limited furnace temperature window and poor lateral mixing, conditions which render SNCR less effective in these units. SNCR has been applied to PC boilers more often to achieve 30 – 50% reductions in response to Reasonably Available Control Technology (RACT) requirements since the technology can be retrofit more easily than other add-on controls. Due to mixing limitations and a brief temperature window in which to react, SNCR is fundamentally less effective at controlling  $\text{NO}_x$  from PC's as compared with other combustion processes.

## **Staged Combustion**

A number of techniques have been employed to reduce the formation of NO<sub>x</sub> by reducing peak flame temperature and/or starving the hottest parts of the flame for oxygen. By staging the combustion process, a longer, cooler flame results, which forms less NO<sub>x</sub>. Staged combustion techniques include Low-NO<sub>x</sub> burners, flue gas recirculation, overfire air, burners out of service, and combinations of these. A collateral impact of staged combustion is an increase in emissions of products of incomplete combustion including CO, VOC and carbon in ash.

## **Gas Reburn**

Natural gas reburn is a control technique that has shown promise as a potential retrofit to existing boilers, and may be capable of reducing emissions of NO<sub>x</sub> to 0.15 lb/MMBTU simply by starving the coal burners for excess oxygen and completing combustion with 12-15% gas in the upper furnace. Application of this technology assumes that natural gas in substantial quantity is already available on site – otherwise it is technically infeasible. In any event, the level of NO<sub>x</sub> control that may be achieved is less than for the other add-on control technologies and therefore it is not considered further in this analysis.

## **Proposed Pulverized Coal-Fired Boiler BACT for NO<sub>x</sub>**

Sithe has proposed to construct and operate the Facility with a combination of LNB and SCR for each of the two proposed boilers. Sithe is proposing to achieve a BACT NO<sub>x</sub> emission rate of 0.06 lb/MMBTU as a 24-hour average during operation based on using Navajo Nation coal from the BHP mine. Sithe's application for the PSD Permit contained a top-down BACT analysis which EPA has independently evaluated.

EPA's independent analysis of available control technologies for pulverized coal fired boilers included reviewing the DOE/NETL (National Energy Technology Laboratory) database, EPA's RACT/BACT/LAER Clearinghouse, EPA's National Coal BACT Workgroup database, the EPA spreadsheet of recently permitted and proposed coal-fired power plants, review of issued permits or applications for permits, discussions with EPA and State permitting staff, trade journals, information from industry conferences and vendor guarantees.

EPA's review of all available data and technologies demonstrates that Sithe's proposed choice of LNB and SCR is the most stringent combination of control technologies available for pulverized coal fired boilers. The NO<sub>x</sub> emission rate of 0.06 lb/MMBTU that Sithe has proposed, particularly because Sithe has proposed to meet 0.06 lb/MMBTU as a 24-hour average, is lower than other NO<sub>x</sub> emissions

rates that have been proposed for or achieved by pulverized coal fired boilers recently.

The National Coal Workgroup database shows that the NO<sub>x</sub> BACT emissions limits in recent PSD permits for pulverized coal fired boilers using LNB and SCR range from 0.07 lbs/MMBTU to 0.10 lbs/MMBTU, often as a 30-day average. Similarly, the information contained in the DOE/NETL's database of information for pulverized coal fired boilers shows that 0.06 lbs/MMBTU is below the lowest NO<sub>x</sub> BACT emission limits for recently permitted facilities. Further examples of NO<sub>x</sub> BACT emissions limits for recently permitted pulverized coal boilers using LNB and SCR, or solely LNB for the Sand Sage facility, is shown below.

<b>Examples of Recently Permitted/Proposed Coal-Fired Power Plants</b>			
Facility	Size (MW)	Emission Controls	NO <sub>x</sub> Emission Rate (lbs/MMBTU)
Thoroughbred (Kentucky)	1500	SCR	0.08 (30-day avg.)
Prairie State (Illinois)	1500	SCR	0.10
Intermountain Power (Utah)	950	SCR	0.07 (30-day avg.)
Longleaf	1200	SCR	0.07 (30-day avg.)
Sand Sage	660	LNB	0.12 - 0.08 (30-day avg.)
Roundup Power (Montana)	780	SCR	0.07 (24-hr avg.)
Longview	600	SCR	0.08 (24-hr avg.)

EPA has also reviewed the decisions of EPA's Environmental Appeals Board (EAB) and the Wisconsin Division of Hearings and Appeals on challenges to the NO<sub>x</sub> BACT decisions in PSD permitting actions for pulverized coal fired boilers. The Nevada Department of Environmental Protection issued a PSD permit to Newmont Nevada Energy Center LLP. The PSD Permit for that facility, which is a 200 MW pulverized coal fired boiler, established a BACT emission limit for NO<sub>x</sub> at 0.067 lbs/MMBTU as a 24 hour average, using LNB and SCR. The Newmont facility will burn coal from the Powder River Basin (PRB). The appropriateness of Newmont's NO<sub>x</sub> BACT emission limit of 0.067 lbs/MMBTU was appealed to the EAB. The petitioner challenged whether 0.067 lbs/MMBTU (24 hour average) was BACT because Sithe had applied for a lower NO<sub>x</sub> BACT

limit (0.06 lbs/MMBTU as a 24 hour average) for DREF. The petitioner also cited a report for Baldwin Generating Station in Illinois, a determination by the Texas Natural Resource Conservation Commission discussing potentially achievable lower NOx emissions limits and a few other sources. *See In Re: Newmont Nevada Energy Investment, LLC*, 12 E.A.D. (June 3, 2005). The EAB recognized the importance of the type of coal being combusted and other relevant case-specific factors in a BACT determination. The EAB was not persuaded by citations to lower NOx emissions rates in trade journals and permits that only required such operation during the ozone season. The EAB recognized that the precise conditions, including the selection of coal type, surrounding the operation of the facility under PSD review should dictate the NOx BACT emissions limit, and held that 0.067 lbs/MMBTU as a 24 hour average was BACT.

The Wisconsin Division of Hearings and Appeal upheld the State's PSD NOx BACT determination during a permit appeal. The Wisconsin Department of Natural Resources (WDNR) determined that a NOx emission limit of 0.06 lbs/MMBTU as a 30 day average was BACT. The WDNR initially permitted the facility with a NOx BACT emission limit of 0.06 lbs/MMBTU as a 30 day average and 0.07 lbs/MMBTU as an annual average. The Judge in that appeal found 0.06 lbs/MMBTU was "consistent with or lower than other BACT NOx emission limits established for other coal-fired utility boilers which were issued air permits contemporaneous with [the Wisconsin facility]." Decision at 10. The Judge modified the PSD permit to remove the higher emissions limit (0.07 lbs/MMBTU) for the annual average so that the permittee was required to meet a NOx BACT emission limit of 0.06 lbs/MMBTU as a 30 day and annual average.

In summary, the two lowest BACT emissions limits for NOx are 0.067 lbs/MMBTU as a 24 hour average for Newmont and 0.06 lbs/MMBTU as a 30 day average for the Wisconsin facility. The NOx BACT emissions limit in the proposed permit for DREF is 0.06 lbs/MMBTU as a 24 hour average, making the proposed NOx BACT emissions limit for DREF the lowest in an issued PSD permit for a pulverized coal fired boiler. When an emission limit is averaged over a shorter period of time (e.g. 24 hours rather than 30 days), it reduces the number of spikes that a facility can experience while still maintaining compliance with the emissions limit. Therefore, the NOx emission limit of 0.06 lbs/MMBTU as a 24 hour average is lower than any other reported BACT emission limit. EPA is proposing BACT for NOx for DREF to be LNB and SCR, meeting an emission limit of 0.06 lb/MMBTU on a 24 hour average.

## **2. Auxiliary Boilers**

The Desert Rock Energy Facility includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBTU/hour. These

boilers will be subject to NSPS 40 CFR 60, Subpart Dc. Total annual fuel use in the three boilers will be limited to 142,560 MMBTU/year, which is equivalent to an average of 550 hours of operation per year per boiler at full load. Based on a review of recent permits for similar boilers and EPA's RACT/BACT/LAER Clearinghouse, the applicant has concluded that BACT for NO<sub>x</sub> for these boilers is 0.10 lb/MMBTU using Low-NO<sub>x</sub> burners. After reviewing the submitted materials, EPA agrees and proposes BACT for NO<sub>x</sub> for the auxiliary boilers to be Low-NO<sub>x</sub> burners and an emission rate of 0.10 lb/MMBTU.

### **3. Emergency Generators**

The Desert Rock Energy Facility includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). These emergency diesel engines will not operate for more than 100 hours/year each. NO<sub>x</sub> emissions during operation will be controlled by only burning low sulfur distillate oil and ignition timing retard with turbocharging and aftercooling. Based on review of recent permits for similar emergency diesel engines and EPA's RACT/BACT/LAER Clearinghouse, the top level of control or lowest NO<sub>x</sub> emission rate is approximately 6.5 g/hp-hr. The applicant has concluded that this level of control represents BACT for the emergency diesel engines. After reviewing the submitted materials, EPA concurs and proposes the use of ignition timing retard with turbocharging and aftercooling with an emission rate of 6.5 g/hp-hr to be BACT for NO<sub>x</sub> for the emergency generators.

## **B. Sulfur Dioxide (SO<sub>2</sub>)**

### **1. Pulverized Coal-Fired Boilers**

Emissions of sulfur dioxide are generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. Approximately 98% of sulfur in solid fuels is emitted upon combustion as gaseous sulfur oxides. Uncontrolled emissions of SO<sub>2</sub> are thus affected by fuel sulfur content alone, and not by the firing mechanism, boiler size, or operation. Many coal-fired boilers limit emissions of SO<sub>2</sub> through the use of low sulfur western coals, including PRB coal. Compared with a high sulfur eastern bituminous coal that may contain as much as 4% sulfur, burning western coal can reduce SO<sub>2</sub> emissions by approximately 70% to 90%. The selection of coal type and sulfur content is therefore one of the aspects that must be considered when making a determination of SO<sub>2</sub> BACT and needs to be considered in conjunction with add-on control alternatives when performing the top-down analysis.

Generally, there are two types of add-on control applicable to a coal-fired boiler: in-situ combustion control (sorbent injection) and post-combustion control (flue

gas desulfurisation). In-situ control is used effectively in CFB boilers, and may be used in a PC boiler by using limestone injection into the furnace, however the level of control that is achievable is not comparable to post-combustion SO<sub>2</sub> control systems. Post-combustion controls applicable to PC boilers are a wet scrubbing system or spray dryer absorber (SDA) using reagents such as lime, limestone, sodium bicarbonate or magnesium oxide.

A comparative ranking of available SO<sub>2</sub> control technologies (see Table 4) must take into consideration multiple variables including coal sulfur content, % removal and the resulting emission rate (lb/MMBTU) in addition to collateral impacts on other pollutants, energy impacts, and other environmental impacts.

**Table 4**  
**SO<sub>2</sub> Control Technologies for Pulverized Coal Boilers**

Pulverized Coal Control Technologies	Control Efficiency Range (% Removal)	Typical Emission Rate (lb/MMBTU)
Wet Flue Gas Desulfurisation	90 - 98	Depends on coal sulfur content (lower with western coal)
Limestone Injection	25 - 35	Depends on coal sulfur content (lower with western coal)
Spray Dryer Absorber	70 - 92	Depends on coal sulfur content (lower with western coal)
Use of Low Sulfur Coal	30 - 90	

### **Wet Flue Gas Desulfurisation**

The most frequently utilized wet flue gas desulfurisation (FGD) technology is the wet limestone spray tower system. Typically, flue gas enters at the bottom of the absorber tower, continues vertically through the limestone/water spray, passes through a mist eliminator to control the re-entrained slurry drops, and then exits the tower. Limestone (calcium carbonate) reacts with the sulfur dioxide to form calcium sulfite. The calcium sulfite may then be oxidized to form calcium sulfate, since it is easier to de-water than calcium sulfite. This can be achieved by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank.

To fully utilize the limestone, the slurry is re-circulated through the tower and a bleed stream is taken off for de-watering. The bleed stream can be de-watered using a variety of techniques, including thickeners, centrifuges and vacuum filters.



The final slurry may contain 10% to 40% water by weight.

Wet scrubbers can also utilize limestone rather than lime. Some of the lime (calcium oxide) becomes calcium hydroxide in water. The slurry of calcium hydroxide and lime is fed to the spray tower. Since the cost of limestone is much less than lime, the limestone alternative is much more common. This is especially the case for medium to high sulfur coals.

### **Spray Dryer Absorber/Limestone Injection**

The spray dryer absorber is located upstream of the particulate collection system, typically fabric filters. The flue gas passes through a spray dryer vessel where it encounters a fine mist of lime slurry. The lime slurry is injected into the spray dryer absorber through either a rotary atomizer or fluid nozzles. The moisture in the droplets evaporates and reacts with the SO<sub>2</sub> in the flue gas to form insoluble calcium salts. The flue gas is cooled to approximately 18 to 30 °F above the adiabatic saturation of the flue gas. The calcium salts have a moisture content of approximately 2 to 3%, which falls to 1% before reaching the particulate control device. When a fabric filter is used as the particulate control device, it allows for further reaction of the lime with the sulfur (and other acid gases) in the flue gas. This is due to the layer of porous filter cake on the surface of the filter that contains the reagent that all flue gas must pass through. This allows for increased efficiency of control of sulfuric acid mist, hydrogen chloride and mercury as compared to wet scrubbers.

### **Use of Low Sulfur Coal**

Any discussion of the relative effectiveness of add on SO<sub>2</sub> control must also take into account the level of uncontrolled SO<sub>2</sub> to be handled, which is highly dependent on the sulfur content of the coal to be burned. Higher removal efficiencies tend to be more practical when there is a high concentration of SO<sub>2</sub> in the flue gas, and vice versa. This is reflected in a comparison of the resulting emission rate in units of lb of SO<sub>2</sub> per MMBTU of fuel burned (or lb of SO<sub>2</sub> per kW produced). For example, a proposed project with a BACT limit of 0.16 lb/MMBTU using an 80% removal control system is environmentally superior to another project with a BACT limit of 0.32 lb/MMBTU and 95% removal. For a project located in the Western U.S., BACT generally includes use of low sulfur western coal as a part of a strategy to limit SO<sub>2</sub> to BACT levels in combination with add-on control.

### **Proposed Pulverized Coal-Fired Boiler BACT for SO<sub>2</sub>**

Sithe has proposed to construct and operate the Facility using a combination of

low sulfur western coal and wet limestone flue gas desulfurisation. Sithe is proposing to achieve an SO<sub>2</sub> BACT emission rate of 0.06 lb/MMBTU as a 24-hour average during operation.

EPA's independent analysis of available control technologies for pulverized coal fired boilers included reviewing the DOE/NETL (National Energy Technology Laboratory) database, EPA's RACT/BACT/LAER Clearinghouse, EPA's National Coal BACT Workgroup database, and the EPA spreadsheet of recently permitted and proposed coal-fired power plants as well as the other sources discussed above for NO<sub>x</sub>.

EPA's review of all available data and technologies demonstrates that the choice of low sulfur coal and wet limestone desulfurisation is the most stringent combination of control technologies available for pulverized coal fired boilers. The emission rate of 0.06 lb/MMBTU that Sithe has proposed, as a 24-hour average, is lower than other SO<sub>2</sub> emission rates that have been proposed for pulverized coal fired boilers recently.

The PSD Permit that Nevada Department of Environmental Protection issued to Newmont Nevada Energy Center, LLP last year allowed dry scrubbing rather than requiring wet limestone desulfurisation. Newmont's PSD permit established an SO<sub>2</sub> BACT emission limit of 0.065 to 0.09 lbs/MMBTU.

EPA is also persuaded that 0.06 lbs/MMBTU SO<sub>2</sub> is BACT for DREF based on the information in the National Coal Workgroup database. The database shows that SO<sub>2</sub> emission limits for recent PSD permits for pulverized coal fired boilers range from 0.09 to 0.30 lb/MMBTU (30-day average). Similarly, the information contained in the Department of Energy's compilation of information for pulverized coal fired boilers shows that 0.06 lbs/MMBTU is below the lowest SO<sub>2</sub> BACT emission limit for recently permitted facilities.

<b>Examples of Recently Permitted/Proposed Coal-Fired Power Plants</b>			
Facility	Size (MW)	Emission Controls	SO <sub>2</sub> Emission Rate (lbs/MMBTU)
Thoroughbred	1500	Wet scrubber	0.167 (30-day avg.) 0.41 (24-hr avg.)
Prairie State	1500	Wet scrubber	0.30
Intermountain Power	950	Wet scrubber	0.09 (30-day avg.) 0.12 (24-hr avg.)
Longleaf	1200	Dry scrubber	0.12 (30-day avg.)

Sand Sage	660	Dry scrubber	0.15 (30-day avg.)
Roundup Power	780	Dry scrubber	0.12 (24-hr avg.)

## 2. Auxiliary Boilers

The Desert Rock Energy Facility also includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBTU/hour. Total annual fuel use in the three boilers will be limited to 142,560 MMBTU/year, which is equivalent to an average of 550 hours/year per boiler at full load. SO<sub>2</sub> emissions will be controlled by only burning low sulfur distillate oil with a maximum sulfur content of 0.05%. No add-on SO<sub>2</sub> controls have ever been applied to similar sources. The burning of low sulfur fuels such as low sulfur distillate oil is the only available SO<sub>2</sub> control option and is the top level of control. Therefore, the applicant is proposing to only burn low sulfur distillate oil (0.05% sulfur maximum) and to restrict total annual fuel consumption to 142,560 MMBTU/year as BACT for the auxiliary boilers. After reviewing the submitted materials we concur with the applicant and propose BACT for SO<sub>2</sub> for the auxiliary boilers to be the burning of low sulfur distillate oil not to exceed 0.05% sulfur content and no more than 142,560 MMBTU/year.

## 3. Emergency Diesel Engines

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). These emergency diesel engines will not be operated for more than 100 hours/year each. No add-on SO<sub>2</sub> controls have ever been applied to similar sources. The burning of low sulfur fuels such as low sulfur distillate oil is the only available SO<sub>2</sub> control option and represents the top level of control. Therefore, the applicant proposes to only burn low sulfur distillate oil (0.05% sulfur maximum) and to restrict operation to 100 hours per year each as BACT for the proposed emergency diesel engines. EPA concurs and proposes BACT for SO<sub>2</sub> for the emergency diesel engines to be burning low sulfur distillate oil and limiting operation to no more than 100 hours per year per engine.

## C. Carbon Monoxide (CO)

### 1. Pulverized Coal-Fired Boilers

Carbon monoxide is formed as a result of incomplete combustion of a hydrocarbon fuel. Control of CO is accomplished by providing adequate fuel residence time, excess oxygen and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased

emissions of NO<sub>x</sub>. Conversely, a low NO<sub>x</sub> emission rate achieved through combustion modification techniques such as Low-NO<sub>x</sub> Burners can result in higher levels of CO formation. Thus, a compromise is established to achieve the lowest NO<sub>x</sub> formation rate possible while keeping CO emission rates at acceptable levels.

CO emissions from pulverized coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. All pulverized coal-fired boilers identified utilize front-end methods such as good combustion control wherein CO formation is suppressed within the boiler. All listings in EPA's RACT/BACT/LAER Clearinghouse for pulverized coal-fired boilers utilize combustion control techniques for CO (see Table 5). While gas-fired combustion turbines have been widely equipped with oxidation catalyst control technology, this technology has not been applied to coal-fired boilers. In addition to oxidizing CO, an oxidation catalyst would oxidize SO<sub>2</sub> to produce SO<sub>3</sub>, which would exacerbate sulfuric acid mist emissions. The SO<sub>2</sub> oxidation rate would be in the range of 5% or more resulting in very high sulfuric acid mist emissions if an oxidation catalyst were to be applied to a coal-fired boiler.

**Table 5**  
**CO Control Technologies for Pulverized Coal Boilers**

Pulverized Coal Control Technologies	Emission Rate (lb/MMBTU)	Technical Feasibility for Pulverized Coal-Fired Boilers
Combustion Controls	0.05 - 0.15	Yes
Oxidation Catalyst	Not determined	May not be feasible

### **Combustion Controls**

Combustion control refers to controlling emissions of CO through the design and operation of the boiler in a manner so as to limit CO formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also tend to reduce emissions of VOC as well as CO. However, this process must be optimized with the efforts to reduce NO<sub>x</sub> emissions, which may increase when steps to lower CO are taken.

### **Catalytic Oxidation**

Catalytic oxidation is the technology that has been used to obtain the most

stringent control level for CO from natural gas-fired turbine combustion units. This technology has never been applied to a coal-fired unit. It is evaluated here to determine if it could be considered transferable technology for application to the proposed pulverized coal-fired boilers. In this alternative, a catalyst would be situated in the flue gas stream to lower the activation energy required to convert products of incomplete combustion (CO and VOC) in the presence of oxygen (O<sub>2</sub>) to carbon dioxide and water. The catalyst permits combination of the reactant species at lower gas temperatures and residence times than would be required for uncatalyzed oxidation.

The catalyst would have to be located at a point where the gas temperature is within an acceptable range. The effective temperature range for CO oxidation is between 600 °F and about 1,000 °F. Catalyst non-selectivity is a problem for sulfur containing fuels such as coal. Catalysts promote oxidation of SO<sub>2</sub> to SO<sub>3</sub> as well as CO to CO<sub>2</sub>. The amount of SO<sub>2</sub> conversion is a function of temperature and catalyst design. Under optimum conditions, formation of SO<sub>3</sub> can be minimized to 5% of inlet SO<sub>2</sub>. This level of conversion would result in a large collateral increase in H<sub>2</sub>SO<sub>4</sub> emissions which aside from the increased ambient air impacts, could result in unacceptable amounts of corrosion to the fabric filter particulate collector, air preheater, ductwork and stack.

The applicant contacted an oxidation catalyst system vendor to determine the technical feasibility of installing this system on a coal-fired boiler. Due to the high particulate loading of the flue gas, variable trace element concentration in the flue gas and the SO<sub>2</sub> loading before air pollution control systems, the vendor stated that they could not provide a catalyst system for coal-fired applications. Consequently, the applicant has determined that oxidation catalyst systems are considered technically infeasible for application to the proposed coal-fired boilers.

### **Proposed Pulverized Coal-Fired Boiler BACT for CO**

Sithe has proposed, and EPA's analysis supports, that the only practical or demonstrated in practice measure to control CO from coal-fired boilers is good combustion practices. Combustion control, and the resulting optimized emission rate to minimize formation of CO while also minimizing NO<sub>x</sub>, therefore represents BACT for the proposed boilers. BACT for CO from the proposed Facility is 0.10 lb/MMBTU. This level is consistent with or lower than recent permits for new coal-fired boilers.

## **2. Auxiliary Boilers**

The Desert Rock Energy Facility includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBTU/hour. Total

annual fuel use in the three boilers will be limited to 142,560 MMBTU/year, which is equivalent to an average of 550 hours/year per boiler at full load. A BACT limit for CO emissions of 0.036 lb/MMBTU and the annual total fuel restriction of 142,560 MMBTU/year are proposed for these boilers, which reflect the lowest emission limits listed in EPA's RACT/BACT/LAER Clearinghouse. After reviewing the submitted materials, EPA concurs with the applicant and proposes BACT for CO from the auxiliary boilers to be an emission limit of 0.036 lb/MMBTU and a fuel limit of 142,560 MMBTU/year.

### **3. Emergency Diesel Engines**

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 100 hours/year each. The applicant proposes a BACT emission limit for these diesel engines of 0.5 g/hp-hr and a limitation of 100 hours of operation per year (each). After reviewing the submitted materials, EPA agrees and proposes BACT for CO from the emergency diesel engines to be a limit of 0.5 g/hp-hr and a limit of 100 hours of operation per year per engine.

## **D. Volatile Organic Compounds (VOC)**

### **1. Pulverized Coal-Fired Boilers**

VOCs are also emitted from coal-fired boilers as a result of incomplete combustion of the fuel. Control of incomplete combustion is accomplished in the same way CO emissions are controlled: by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

VOC emissions from coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. All coal-fired boilers identified utilize front-end methods such as combustion control wherein VOC formation is suppressed within the boiler. All listings in EPA's RACT/BACT/LAER Clearinghouse for coal-fired boilers utilize combustion control techniques for VOC. While gas-fired combustion turbines have been widely equipped with oxidation catalyst control technology, this technology is not easily applied to coal-fired boilers.

A review of EPA's RACT/BACT/LAER Clearinghouse, and the applicant's review of recent permit decisions, indicates levels of VOC control which may be achieved for pulverized coal-fired boilers. Emission levels and control technologies have been identified and ranked in Table 6.

**Table 6**  
**VOC Control Technologies for Pulverized Coal Boilers**

Pulverized Coal Control Technologies	Emission Rate (lb/MMBTU)	Technical Feasibility for Pulverized Coal-Fired Boilers
Combustion Controls	0.002 - 0.01	Yes
Oxidation Catalyst	Not determined	May not be feasible

### **Combustion Control**

Combustion control refers to controlling emissions of VOC through the design and operation of the boiler in a manner so as to limit VOC formation. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: providing sufficient excess air, staged combustion to complete burn out of products of incomplete combustion, sufficient residence time, and good mixing. All of these factors also have the by-product of reducing the emissions of CO. Pulverized coal-fired boilers are designed specifically for efficient fuel combustion with thorough mixing and residence time at temperature, plus staged combustion. The applicant believes that this level of combustion control represents BACT for the proposed boilers.

### **Add-On Emission Controls**

Catalytic oxidation and other add-on controls are not applicable to coal-fired boilers as discussed in the CO BACT section above.

### **Proposed Pulverized Coal-fired Boiler BACT for VOC**

Sithe has proposed, and EPA's analysis supports, that the only practical or demonstrated in practice measure to control VOC emissions from coal-fired boilers is good combustion. Combustion control, and the resulting optimized emission rate to minimize formation of VOC while also minimizing NO<sub>x</sub>, therefore represents BACT for the proposed boilers. Sithe is proposing a VOC BACT limit of 0.003 lb/MMBTU, which is lower than the lowest emission rate in recent permits for new coal-fired boilers.

## **2. Auxiliary Boilers**

The project includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBTU/hour. Total annual fuel use in the three boilers will be limited to 142,560 MMBTU/year, which is equivalent to an average of 550 hours/year per boiler at full load. The applicant proposes BACT for VOC emissions from the auxiliary boilers to be an emission limit of 0.0024 lb/MMBTU and a total fuel restriction of 142,560 MMBTU/year based on EPA's RACT/BACT/LAER Clearinghouse. After reviewing the submitted materials, EPA concurs with the applicant and proposes BACT for VOC from the auxiliary boilers to be an emission limit of 0.0024 lb/MMBTU and a fuel limit of 142,560 MMBTU/year.

## **3. Emergency Diesel Engines**

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 100 hours/year each. The applicant proposes a BACT emission limit for these diesel engines of 0.3 g/hp-hr and an operating restriction of 100 hours per year (each) for VOC from these units. After reviewing the submitted materials, EPA agrees and proposes BACT for VOC from the emergency diesel engines to be a limit of 0.3 g/hp-hr and a limit of 100 hours of operation per year per engine.

## **E. Particulate Matter**

### **1. Pulverized Coal-Fired Boilers**

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation, coal properties and emission controls. Particulate matter will be emitted from the pulverized coal-fired boilers as a result of entrainment of incombustible inert matter (ash) and condensable substances such as acid gases. Both particulate matter (PM), and particulate matter smaller than 10 micrometer diameter (PM<sub>10</sub>) require the application of BACT under the Federal PSD program. Particulate matter is total filterable particulate matter as determined by EPA Method 5 or 17. PM<sub>10</sub> includes filterable particulate matter smaller than a 10 micrometer diameter as determined by EPA Method 201 or 201A and condensable particulate matter as determined by EPA Method 202.

A review of EPA's RACT/BACT/LAER Clearinghouse indicates several levels of particulate control that may be achieved for pulverized boilers. Emission levels and control technologies have been identified and ranked in Table 7. There are



almost 50 coal-fired boilers listed in the EPA's BACT/LAER Clearinghouse with emission limits for filterable particulate matter that are less than or equal to 0.02 lb/MMBTU. All but one of these listings report that a fabric filter is utilized (the AES Puerto Rico facility is the only exception). The control of PM using fabric filtration is clearly demonstrated for coal-fired boilers. Wet control techniques (venturi or other high-energy scrubbers), on the other hand, do not represent a recently applied or demonstrated control technique for coal-fired boilers and do not offer more stringent levels of control of particulate matter than fabric filters.

**Table 7**  
**Particulate Control Technologies for Pulverized Coal Boilers**

Pulverized Coal Control Technologies	Typical Emission Rate (lb/MMBTU)	Technical Feasibility for Pulverized Coal-Fired Boilers
Fabric Filter	0.01 - 0.02	Yes
Electrostatic Precipitator	0.015 - 0.025	Yes
High Energy Wet Scrubber	Not determined	No applications for recent coal-fired boilers

Note: Emission levels represent steady-state values at base load, for front-half (filterable) only.

### **Fabric Filter**

Fabric filters are widely used for particulate control from PC boilers and are capable of over 99% control efficiency. According to EPA's Fabric Filter Fact sheet (EPA, 2000), "flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are most common type of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Bags may be 6 to 9 m (20 to 30 ft) long and 13 to 31 centimeters (cm) (5 to 12 inches) in diameter. Groups of bags are placed in isolatable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

The advantages of fabric filters include:

- 1) High collection efficiency for a broad range of particle sizes;

- 2) Flexibility in design (various methods of cleaning methods and filter media);
- 3) Wide range of volumetric capacities;
- 4) Reasonable pressure drops and power requirements; and
- 5) Handles a wide range of solid materials.

Some disadvantages of fabric filters are as follows:

- 1) Danger of explosion in the presence of a spark; or catastrophic bag damage due to fire; and
- 2) Wet particles can agglomerate on a filter cloth if the waste gases are at a temperature close to their dew point.

### **Proposed Pulverized Coal-fired Boiler BACT for Particulate Matter**

Fabric filters and electrostatic precipitators (ESP's) represent technically feasible options for the control of particulate matter from coal-fired boilers. Wet control techniques (scrubbers), on the other hand, do not represent a demonstrated control technique and do not offer more stringent levels of control of particulate matter than fabric filters or ESP's. ESP's are generally less effective at controlling fine particulate, and are generally incapable of any additional control of other pollutants such as acid gases or mercury, and are not considered to represent the top level of available control technology.

Based on numerous projects using fabric filters, Sithe has proposed to use a fabric filter as BACT to limit PM emissions to 0.010 lb/MMBTU. In addition, Sithe proposes to limit total PM<sub>10</sub> (including condensable PM<sub>10</sub>) emissions to 0.02 lb/MMBTU. Very little data are available on condensable PM<sub>10</sub> emissions from coal-fired boilers burn western coal, and for that reason Sithe has proposed a condensable PM<sub>10</sub> limit of 0.02 lb/MMBTU as BACT for total PM<sub>10</sub>, but requests a trial period of three years to determine the feasibility of this exceptionally low limit. The proposed PM emission rate is lower than the lowest emission level for a new coal fired boiler (Wygen 2 in Wyoming) listed in EPA's RACT/BACT/LAER Clearinghouse or the other reference materials discussed in the BACT analysis for NO<sub>x</sub> and SO<sub>2</sub>.

EPA's independent review of the materials supports Sithe's analysis that proposed BACT for PM emissions from the coal-fired boilers is a fabric filter with an emission limit of 0.01 lb/MMBTU. In addition, EPA is proposing BACT for total

PM<sub>10</sub> emissions to be a fabric filter with an emission limit of 0.02 lb/MMBTU. However, EPA does not believe that a three year trial period of the 0.02 lb/MMBTU emission limit is warranted. EPA believes that the feasibility of the 0.02 lb/MMBTU emission limit can be determined during the first 18 months of operation and will propose an 18 month trial period commencing upon initial startup.

## **2. Auxiliary Boilers**

The project includes three small distillate oil-fired auxiliary boilers with heat input capacities of approximately 86.4 MMBTU/hour. Total annual fuel use in the three boilers will be limited to 142,560 MMBTU/year, which is equivalent to an average of 550 hours/year per boiler at full load. The applicant is proposing BACT limits for PM and PM<sub>10</sub> based on the use of very low sulfur distillate oil, the total annual fuel limitation of 142,560 MMBTU/year, and EPA emission factors published in AP-42 and EPA's RACT/BACT/LAER Clearinghouse. For PM, BACT for the auxiliary boilers is the annual fuel limitation, the use of 0.05% sulfur distillate oil, and an emission limit of 0.014 lb/MMBTU based on the EPA emission factor of 2 lb/1000 gal. For PM<sub>10</sub>, BACT includes an emission limit of 0.024 lb/MMBTU based on adding the condensable PM<sub>10</sub> emissions of 0.01 lb/MMBTU (1.3 lb/1,000 gal based on AP-42) to the PM emission rate. After reviewing the submitted materials, EPA concurs and proposes BACT for PM emissions from the auxiliary boilers to be an emission rate 0.014 lb/MMBTU, the use of 0.05% sulfur distillate oil, and an annual fuel limitation of 142,560 MMBTU/year. For PM<sub>10</sub>, EPA is proposing BACT to be an emission limit of 0.024 lb/MMBTU, the use of 0.05% sulfur distillate oil, and an annual fuel limitation of 142,560 MMBTU/year.

## **3. Emergency Diesel Engines**

The project includes two emergency diesel generators (1,000 kW each) and two diesel generator powered firewater pumps (180 kW each). The diesel engines will not be operated for more than 100 hours/year each. The applicant proposes that BACT emission limits include the 100 hour per year (each) operating restriction, and limits of 0.19 g/hp-hr and 0.22 g/hp-hr PM and PM<sub>10</sub>, respectively, based on EPA emission factors in AP-42. After reviewing the submitted materials, EPA concurs and proposes BACT for PM and PM<sub>10</sub> from the emergency diesel engines to be emission limits of 0.19 g/hp-hr and 0.22 g/hr-hr respectively and an operating limit of not more than 100 hours/year per engine.

## **4. Material Handling Sources**

Sithe has proposed that its material handling sources will be controlled by dust suppression systems, enclosures and/or fabric filters. For example, conveyors will be constructed of enclosed design in order to eliminate wind-blown dust emissions.

Conveyors will lead to transfer towers, bunkers or silos that will include a “coal drop”. Such structures will also be of enclosed design and will be evacuated (when operating) through fabric filter units, sometimes referred to as “bin vent filters”. Enclosed design of materials handling system and evacuation through bin vent filters represents BACT for material handling equipment.

In addition, coal handling systems will be subject to NSPS Subpart Y and limestone handling systems will be subject to NSPS Subpart OOO. A review of the EPA RACT/BACT/LAER Clearinghouse gives a range of control efficiencies from baghouses. Although the most recent permits for coal fired power plants, Bull Mountain and Roundup Power Projects, determined that BACT was 0.01 gr/dscf for all sources, the Mid America permit identified 0.005 gr/dscf for baghouses associated with coal sources and 0.01 gr/dscf for other material handling activities. The applicant proposes to also specify these filterable PM/PM<sub>10</sub> emissions limits of 0.005 gr/dscf for coal and 0.01 gr/dscf for limestone and other materials.

The applicant also pointed out that as a mine-mouth power plant, the Desert Rock Energy Facility will avoid fugitive dust emissions associated with rail unloading operations and active on-site storage piles. The inactive storage pile will be covered with soil, geotextile or chemical crusting agents to prevent both weathering of the coal and fugitive dust emissions. When coal is added to or reclaimed from the inactive pile, which is expected to be very infrequently, the coal will be wetted and/or treated with chemical agents to minimize any emissions of fugitive dust. The Applicant believes that these operational measures, and those of the NSPS for coal handling operations (Subpart Y), represent BACT for inactive storage and associated coal handling operations. After reviewing the submitted materials, EPA concurs and proposes as BACT for PM/PM<sub>10</sub> from materials handling sources that all conveyors, transfer towers and silos be enclosed and vent to a fabric filter with emission limits of 0.005 gr/dscf for coal and 0.01 gr/dscf for limestone and other materials. In addition, the inactive coal storage pile will be covered with soil or other crusting agents and when coal is added or reclaimed it will be wetted and/or treated with chemical agents to minimize fugitive dust emissions.

## **F. Sulfuric Acid Mist (H<sub>2</sub>SO<sub>4</sub>)**

### **1. Pulverized Coal-Fired Boilers**

Emissions of sulfuric acid mist are generated in fossil fuel-fired sources from the oxidation of sulfur present in the fuel. The amounts of sulfur or SO<sub>2</sub> that are oxidized to sulfuric acid mist may be affected by trace metal catalysis.

In addition to applying BACT, the applicant recognizes that sulfuric acid mist is a

precursor to the formation of regional haze, and for this reason is proposing to include active control of sulfuric acid mist in the design of the Desert Rock Energy Facility. As a result, an additional stage of acid gas removal using hydrated lime (a proprietary technology) has been included upstream of the fabric filter to remove sulfuric acid mist before it enters the wet scrubber. The application of this technology will result in emission levels lower than those permitted for Thoroughbred (with an add-on WESP), and represents a sulfuric acid mist emission rate of 0.004 lb/MMBTU. After reviewing the submitted materials, EPA concurs and proposes BACT for sulfuric acid mist from the PC boilers to be the use of hydrated lime injection and an emission limit of 0.004 lb/MMBTU.

## **2. Auxiliary Boilers and Diesel Generators**

No control alternatives beside the use of very low sulfur fuels have been identified for controlling emissions of sulfuric acid mist from industrial boilers or emergency diesel generators. BACT for sulfuric acid mist for the proposed auxiliary boilers and emergency diesel engines is the use of low sulfur (0.05% S) distillate oil. After reviewing the submitted materials, EPA agrees and proposes BACT for the control of sulfuric acid mist from the auxiliary boilers and the emergency diesel generators to be the use of distillate fuel oil with a sulfur content less than 0.05%.

## **G. Hydrogen Fluoride (HF)**

Emissions of hydrogen fluoride are generated in fossil fuel-fired sources from the oxidation of fluorine present in the fuel. For the PC boilers, the same proprietary acid gas pre-control technology proposed for the control of sulfuric acid mist will control hydrogen fluoride emissions through the injection of hydrated lime before the fabric filter, with additional removal expected from the wet limestone scrubbing. The applicant is proposing a hydrogen fluoride emission rate of 0.00024 lb/MMBTU based on an assumed concentration of fluorine in the coal of 100 ppm (estimated 98% control) as BACT. This emission rate is consistent with or lower than all recent BACT decisions.

No appreciable HF is emitted from distillate oil-fired industrial auxiliary boilers or emergency diesel engines, and the use of low fluorine bearing fuel (very low sulfur distillate oil) represents BACT for HF for these emission sources. After reviewing the submitted materials, EPA concurs and proposes BACT for emissions of hydrogen fluoride to be the use of hydrated lime injection and an emission limit of 0.00024 lb/MMBTU.

## **H. Lead (Pb)**

Emissions of lead are generated in fossil fuel-fired sources from the impurities present in the fuel. Since lead is emitted as solid particulate from coal-fired boilers, it is already included in the PM and PM<sub>10</sub> emission rates selected as BACT. BACT for lead emissions from the proposed PC boilers is the control of PM emissions using fabric filtration

(baghouse), and the emission limits determined to represent BACT for PM<sub>10</sub>.

For distillate oil-fired industrial auxiliary boilers and emergency diesel engines, the use of low ash fuel such as distillate oil represents BACT.

## **I. Summary of BACT Emission Levels**

The BACT levels determined through this evaluation for the Desert Rock Energy Facility are summarized in Tables 8 thru 11.

**Table 8**  
**Summary of Proposed BACT Emission Limits for Pulverized Coal Boilers**

Pollutant	Emission Limit (lb/MMBTU)	Control Technology
NO <sub>x</sub>	0.06, 24-hour average	Low NO <sub>x</sub> Burners and SCR
SO <sub>2</sub>	0.06, 24-hour average	Low sulfur western coal, hydrated lime injection before the fabric filter, and wet limestone desulfurisation
CO	0.10, 24-hour average	Good combustion practices
VOC	0.003, 3-hour average	Good combustion practices
PM	0.01, 6-hour average	Baghouse
PM <sub>10</sub>	0.02, 6-hour average	Baghouse
H <sub>2</sub> SO <sub>4</sub>	0.004, annual average	Low sulfur western coal, hydrated lime injection before the fabric filter, and wet limestone desulfurisation
HF	0.00024, annual average	Hydrated lime injection before the fabric filter, and wet limestone desulfurisation
Pb	0.00020, quarterly	Baghouse

Note: EPA test methods require that the emission limits in the permit for H<sub>2</sub>SO<sub>4</sub>, HF, and Pb be measured as 3-hour averages.

**Table 9**  
**Summary of Proposed BACT Emission Limits for the Auxiliary Boilers**

Pollutant	Emission Limit (lb/MMBTU)	Control Technology
NO <sub>x</sub>	0.10, 3-hour average	Low NO <sub>x</sub> Burners
SO <sub>2</sub>	0.05, 3-hour average	Low sulfur distillate fuel (0.05%)
CO	0.036, 3-hour average	Good combustion practices
VOC	0.0024, 3-hour average	Good combustion practices
PM	0.01, 3-hour average	Low sulfur distillate fuel oil and good combustion practices
PM <sub>10</sub>	0.024, 3-hour average	Low sulfur distillate fuel oil and good combustion practices
H <sub>2</sub> SO <sub>4</sub>	0.00087, annual average	Low sulfur distillate fuel (0.05%)

Notes: 1) PM is defined as filterable particulate matter as measured by EPA Method 5.  
2) PM10 is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. Because PM10 includes condensable particulate matter and PM does not include condensable particulate matter, PM10 emissions are higher than PM emissions.

**Table 10**  
**Summary of Proposed BACT Emission Limits for the Emergency Generators**

Pollutant	Emission Limit (lb/MMBtu)	Control Technology
NO <sub>x</sub>	6.5 g/hp-hr	Ignition timing retard, turbo-charging and after-cooling
SO <sub>2</sub>	0.19 g/hp-hr	Low sulfur distillate fuel (0.05%)
CO	0.5 g/hp-hr	Good combustion practices
VOC	0.3 g/hp-hr	Good combustion practices
PM/PM <sub>10</sub>	0.24 g/hp-hr	Low sulfur distillate fuel oil and good combustion
H <sub>2</sub> SO <sub>4</sub>	0.006 g/hp-hr	Low sulfur distillate fuel (0.05%)

**Table 11**  
**Summary of Proposed BACT Emission Limits for the Materials Handling System**

Pollutant	Emission Limit (lb/MMBTU)	Control Technology
PM/PM <sub>10</sub>	0.005 gr/dscf (filterable) for coal handling baghouses and 0.01 gr/dscf (filterable) for other materials	Enclosures, dust suppression, and fabric filters

**J. Circulating Fluidized Bed Technology**

Normally, for each pollutant being regulated in a PSD permit, EPA evaluates control technologies through a “top-down” BACT determination process for each unit at the facility that emits the regulated pollutant (see Section VI above). However, EPA is comparing the emissions from Circulating Fluidized Bed Technology (CFB) separately because an applicant must choose either a pulverized coal boiler or CFB for all pollutants. Therefore, EPA in this permitting evaluation is comparing the two technologies separately.

**Table 12**  
**Range of Emissions Control from Coal Combustion Technologies**

Coal Technology	Efficiency (%)	% NO <sub>x</sub> Controlled	% SO <sub>2</sub> Removed
Sub-critical PC	34 to 37%	90% (add-on)	92 to 96% (add-on)
Super-critical PC	39 to 45%	90% (add-on)	92 to 96% (add-on)
CFB	34 to 37%	50 to 80%	75 to 92%

Notes: CFB control efficiencies are dependent on sorbent activity and injection rates.

CFB suspends crushed coal in upward flowing air and a “bed” of inert solids, enhancing the turbulent mixing of the air with the coal. In a CFB, the average temperature within the combustion zone can be maintained at less than 2,000 degrees F, while contact with fluidized solids can increase combustion reaction rate and heat transfer. This technology was first introduced to efficiently utilize a wide variety of off-spec, variable or waste fuels and also as a way to decrease inherent pollutant emissions. In a CFB, NO<sub>x</sub> formation is limited by maintaining low temperatures (1,600 °F to 2,000 °F) within the combustion zone. The hot cyclone of the CFB is an ideal location for injection of ammonia (called selective non-catalytic reduction) for additional NO<sub>x</sub> control. A sulfur-adsorbing reagent,



such as limestone or dolomite, is added to the bed which can achieve a 90-92% capture of SO<sub>2</sub> within the CFB boiler process itself. Efficiencies for standard atmospheric circulating fluidized bed combustion units range from 36 to 38%.

The most recent atmospheric CFB plants currently operating include:

- Tractebel Red Hills in Choctaw, MS (operating since mid 2001)
- First Energy Bay Shore power plant in Oregon, OH (operating since May, 2000)
- AES Warrior Run in Cumberland, MD (operating since February, 2000)
- AES Guayama, PR (operating with very low SO<sub>2</sub> limits)
- JEA Northside (an earlier generation Foster Wheeler unit)

The majority of support systems for fluidized bed boilers are very similar to pulverized coal operations; however, CFB technology has inherent advantages in flexibility to utilize low grade fuels and, as a result, may have lower fuel costs relative to other coal technologies because they are able to burn less expensive fuels. CFBs have long been considered “Clean Coal” technology due to the inherent limitation of emissions of SO<sub>2</sub> and NO<sub>x</sub> from within the process itself, without the need for add-on pollution control equipment. Disadvantages include limited unit size (about 300 MW maximum), somewhat more complex equipment and operations, and the generation of large quantities of lime-rich dry CFB residue solid waste.

The conclusions and concerns regarding CFB technology that were expressed in Sithe’s supplemental analysis are listed below:

- Five or six CFB units would be required instead of two pulverized coal boilers to achieve the planned Desert Rock power output. The loss of economy of scale would significantly increase the capital and operational costs of a CFB plant.
- On a lb/MMBTU basis, most emissions from a CFB plant would be similar to or in some cases higher than the proposed Facility’s emissions.
- Sithe estimates the heat rate for a CFB plant would be about 9,950 Btu/kWh while the heat rate for Desert Rock is 8,792 Btu/kWh (net, higher heating value basis). For the same net electricity production and emission rates, a CFB plant would generate 11% more emissions than Desert Rock.
- On an annual ton/yr basis, all emissions from a CFB plant would be higher than the proposed Facility’s emissions due to the higher heat rate.

**Table 14**  
**Proposed Desert Rock Emission Comparison to a New CFB Plant**

Parameter	Desert Rock	CFB	Units	Comments
Average heat rate	8,792	9,775	Btu/kWh	Sub-critical CFB. Super-critical CFBs are under development.
SO <sub>2</sub> emission rate	0.060	0.0576	lb/MMBTU	Sevier Power October 12, 2004 permit limits SO <sub>2</sub> emissions to 0.05 lb/MMBTU as a 24-hr average and 0.022 lb/MMBTU as a 30-day average. Desert Rock design fuel contains 2.62 times as much sulfur on a lb/MMBTU basis.
SO <sub>2</sub> emissions	2,998	3,258	tons/yr	1,366 net MW, 95% capacity factor
NO <sub>x</sub> emission rate	0.060	0.10	lb/MMBTU	Sevier Power October 12, 2004 permit.
NO <sub>x</sub> emissions	2,998	5,656	tons/yr	1,366 net MW, 95% capacity factor
PM <sub>10</sub> emission rate	0.010	0.010	lb/MMBTU	Filterable PM <sub>10</sub> only, no condensable PM <sub>10</sub> data are available. Filterable PM emissions from a baghouse will be similar for both combustion technologies.
PM <sub>10</sub> emissions	500	566	tons/yr	1,366 net MW, 95% capacity factor
VOC emission rate	0.0030	0.005	lb/MMBTU	
VOC emissions	150	283	tons/yr	1,366 net MW, 95% capacity factor
CO emission rate	0.10	0.10	lb/MMBTU	
CO emissions	4,997	5,656	tons/yr	1,366 net MW, 95% capacity factor

Sulfuric acid mist emission rate	0.0040	0.0063	lb/MMBTU	Sevier Power October 12, 2004 permit limits H <sub>2</sub> SO <sub>4</sub> emissions to 0.0024 lb/MMBTU as a 24-hr average. Desert Rock design fuel contains 2.62 times as much S on a lb/MMBTU basis.
Sulfuric acid mist emissions	200	356	tons/yr	1,366 net MW, 95% capacity factor

Note: EPA is aware of permit that was recently proposed by EPA Region 8 for Deseret Power that contains emission rates slightly lower than the above for SO<sub>2</sub> and NO<sub>x</sub>.

After reviewing the submitted materials, as well as our own coal-fired boiler databases, EPA concludes that CFB is not an appropriate technology for this project and will result in higher emissions than the Facility as proposed.

#### **K. Integrated Gasification Combined Cycle Technology**

Consideration of Integrated Gasification Combined Cycle (IGCC) technology, as an alternative to a pulverized coal fired boiler, has not been included in Step 1 of the BACT analyses above, since IGCC would be redefining the source. In preparing the draft permit, EPA did consider whether IGCC is a BACT option, but concluded it is not because it would fundamentally change the basic design of the proposed source. Prior to reaching this conclusion, EPA did, however, request detailed information from Sithe regarding whether or not IGCC would be technically feasible using Navajo Nation coal from the BHP mine. Correspondence from Sithe on this topic has been included in the Administrative Record for this permit action.

### **VII. AIR QUALITY IMPACTS**

The PSD regulations require an air quality analysis to determine the impacts of the proposed project on ambient air quality. For all regulated pollutants emitted in significant quantities, the analysis must consider whether the proposed Facility will cause a violation of (1) the National Ambient Air Quality Standards (NAAQS), and (2) the applicable PSD increments. A discussion of the general approach, air quality model selection, significant impact levels, PSD increment consumption, and the project's compliance with ambient air quality standards is presented below.

EPA's conclusion is that Sithe used appropriate modeling procedures and followed applicable guidance documents demonstrating that the proposed project will not violate any NAAQS or PSD increment, and will not have an adverse impact on any Air Quality Related Value (AQRV) at any Class I area.

In summary, the proposed Facility's impact will be well below the significant impact level for NO<sub>2</sub> and CO. The proposed Facility's impact will exceed the significant impact level for SO<sub>2</sub> and PM<sub>10</sub>, thereby triggering a cumulative impact analysis. The cumulative impact analysis Sithe submitted, however, demonstrated that the proposed Facility will not cause or contribute to an exceedance of the SO<sub>2</sub> or PM<sub>10</sub> NAAQS or PSD increments. The proposed Facility will not exceed the NAAQS for lead (Pb). Finally, the proposed Facility will not have a significant impact on acid deposition at any Class I area, or on the acid-neutralizing capacity of sensitive lakes. Sithe provided substantial additional modeling in response to requests from the Federal Land Managers (FLMs) to address potential concerns about visibility impacts at Class I areas. The FLMs did not find that the proposed Facility will result in an adverse impact on visibility in the Class I areas.

#### **A. Meteorological and Background Ambient Air Quality Data**

The ambient impact analysis required Sithe to provide representative meteorological data as an input into the air quality model. Recently, EPA updated its Guidance to allow applicants to use three years of prognostic meteorological data (i.e., data from a weather model), providing a full three-dimensional wind field, in lieu of data collected from one fixed station. This kind of data is a necessary input to the chosen air quality model, CALPUFF (see below). Sithe originally used data from RUC2 ("Rapid Update Cycle"), a National Weather Service model that incorporates data from many sources, including regular weather stations, NEXRAD radar stations, and satellites. After consultation with and concurrence by the National Park Service, Sithe updated the modeling using data from the MM5 meteorological model at a higher spatial resolution. CALMET is a preprocessor that prepares the meteorological fields for input to CALPUFF by incorporating local weather observations, and also local terrain effects on the wind flow. Various CALMET input options for accomplishing this, such as radius of influence of observation stations, were provided by the National Park Service (NPS). These approaches meet EPA Guidance requirements for meteorological data.

Sithe was also required to provide representative background air quality data. For the NAAQS compliance analysis, Sithe added background concentration to modeled concentrations, and compared the total to the NAAQS. To determine the background concentration, Sithe used the closest monitors to the site of the proposed Facility which are 22-24 km away in Farmington, New Mexico for SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>10</sub>, and O<sub>3</sub> and 136 km away in Rio Rancho, New Mexico for CO. EPA has determined that these monitors will record higher background concentrations of pollutants than we would expect closer the DREF site because Farmington and Rio Rancho have much greater residential and commercial activity than the project site on the Navajo Nation. We have also determined that the Farmington and Rio Rancho monitors are regionally representative because they record the multi-day buildup of pollutants in the general Four Corners area which is important since pollution tends to mix throughout the basin over several days. The background data recorded by the Farmington and Rio Rancho monitors is used only to add to the modeled impact for comparison to the NAAQS, and not for comparison to the PSD

increments. The information from the monitors and Sithe's modeling demonstrates that the total project impact, including background, will be at most 44% of the NAAQS.

## **B. Modeling Methodology**

The model recommended by the Federal Land Managers (FLMs) for analyzing impacts on Class I areas, which are typically rather distant, is CALPUFF. EPA guidance also recommends the use of CALPUFF in near-field Class II analyses if there are complex winds, for which the standard plume models ISCST3 or AERMOD would be inadequate. In CALPUFF, the individual puffs composing a plume may follow independent paths, which is a much more realistic simulation than the single straight line plume assumed in ISCST3 and AERMOD. As shown by Sithe, the area surrounding the site for the proposed Facility is subject to complex winds. The varying strengths of competing regional flows and the more local upslope / downslope flows driven by solar heating mean that flow reversals can occur. This condition is exacerbated by the complex terrain in the area and its non-uniform slopes. Multi-day stagnation is also an issue. These conditions can be handled by CALPUFF, but not by the standard plume models. Therefore, Sithe's choice of CALPUFF for the Class II analysis as well as the Class I analysis is correct and provides consistency with the approach required for Class I areas.

In addition to the meteorological inputs discussed above, an air quality model needs inputs characterizing emissions sources. Sithe modeled the proposed Facility's emissions at their proposed maximum allowable emission rates. Sithe's approach guarantees a conservative air quality assessment meaning that the assessment will predict higher impacts than will occur. (For example, for the 3-hour SO<sub>2</sub> NAAQS, Sithe modeled the main stack at 50% higher than the proposed PSD permit's allowable 24-hour average maximum, i.e. Sithe modeled the SO<sub>2</sub> emissions at 0.09 lb/MMBtu although the proposed PSD permit will only allow the Facility to emit SO<sub>2</sub> at 0.06 lbs/MMBtu). Sithe chose to model the proposed Facility's emissions conservatively to account for short-term variability that might occur during any 24-hour period. Sithe also used inputs for the proposed Facility's stack height, temperature, and exit velocity, which determine the plume's buoyancy and momentum, and hence the emissions' distance from the ground. Because these factors vary with the work load of the source, Sithe performed load screening, which is an estimate of impacts under different load conditions, with the SCREEN3 model, and then with CALPUFF itself. Sithe then used the worst case scenario, assuming 100% load, for the rest of the modeling.

EPA recognizes that nearby buildings can cause plume downwash, leading to high pollutant concentrations. Sithe used the model option to simulate this effect for the proposed project's auxiliary boilers, diesel generators and fire pumps. Sithe did not use this model option for the main stacks of the two proposed pulverized coal fired boilers, because Sithe has proposed to construct a stack that will be sufficiently tall to avoid downwash. Sithe's proposed stack height of 917 feet was determined through a Good Engineering Practice (GEP) stack height analysis, using the BPIP software EPA provides for that purpose. The procedures that Sithe followed meet EPA guidelines.

The final inputs are the locations, or receptors, at which the model will compute pollutant concentrations. Sithe followed good receptor placement procedures that are in accordance with EPA guidelines. This procedure includes a set of receptors out to 50 km from the source, which is standard for Class II area analyses, but Sithe also included additional sets of receptors that are progressively more closely spaced nearer the source, and also fence line receptors. Sithe used dense receptor grids in areas with potentially high impacts, i.e. hillsides where plume impaction can occur. Other sets of receptors are prescribed by the FLMs for each Class I area; all 15 Class I areas within 300 km of the proposed Facility were modeled. Finally, receptors were modeled at 26 distant sensitive Class II areas, such as National Historic Parks, Wilderness Areas, and National Monuments; while these are not Class I areas, they are of special concern to the FLMs.

The proposed Facility's modeled impacts are shown in Table 15 and 16 below. The PSD regulations do not allow a project to make a "significant" contribution to a violation of the NAAQS or of the PSD increment. That is, the applicant must show that its own impact is below the Significant Impact Level (SIL), or else show that there is no violation at locations where its impact is above the SIL. The proposed Facility's impact does not exceed the SIL for NO<sub>2</sub> and CO, which demonstrates the proposed Facility's compliance with the NAAQS and PSD increment for those pollutants.

The proposed Facility's modeled impacts from PM<sub>10</sub> and SO<sub>2</sub> exceeded the SIL, triggering the requirement for a cumulative analysis for those two pollutants. Sithe's cumulative analysis demonstrated that the proposed Facility would remain well below the NAAQS and PSD Class II increment.

For Class I areas, Sithe's modeling showed that the emissions from the Facility could potentially have an impact on an Air Quality Related Value (AQRV). Specifically, Sithe's modeling indicated that the Facility's emissions would result in greater than 5% extinction of visibility on at least 1 day at 11 of the surrounding 15 Class I areas. The FLMs requested Sithe to perform additional modeling. Sithe performed several rounds of additional modeling to evaluate if the Facility's emissions would have an adverse impact on Class I area visibility. On April 25, 2006, the United States Forest Service (USFS) sent a letter to EPA referring to a "mitigation strategy" that Sithe had proposed to the FLMs. The USFS letter indicated that Sithe's performance of the mitigation strategy would be sufficient to alleviate its concerns about visibility. The USFS letter requested EPA to include the mitigation strategy in Sithe's PSD permit so that Sithe's proposal would be federally enforceable. EPA had subsequent discussions with the FLMs to explain EPA's preference for the mitigation strategy to remain in a side agreement between Sithe and the FLMs rather than in Sithe's PSD permit. We understand that Sithe and the FLMs are continuing to discuss appropriate mechanisms other than the PSD permit to memorialize Sithe's commitment to perform the mitigation strategy. Accordingly, EPA has concluded it is appropriate to propose approval of the PSD permit while Sithe and the FLMs continue to discuss memorializing Sithe's commitment to perform the agreed upon mitigation strategy.

**Table 15**  
**Maximum Predicted Air Quality Impacts from the Proposed Project**

Pollutant	Averaging Period	Modeled Impact	SIL (ug/m <sup>3</sup> )	PSD Class II Increment (ug/m <sup>3</sup> )	NAAQS (ug/m <sup>3</sup> )
NO <sub>x</sub>	Annual	0.56	1	25	100
SO <sub>2</sub>	3-hour	271.2	25	512	1300
	24-hour	23.6	5	91	365
	Annual	0.41	1	20	80
PM <sub>10</sub>	24-hour	27.73	5	30	150
	Annual	1.75	1	17	50
CO	1-hour	1375.7	2000	N/A	40000
	8-hour	465.2	500	N/A	10000
Pb	Quarterly	0.0028	N/A	N/A	2

Note: For 3-hour averages, an SO<sub>2</sub> emission rate of 0.09 lb/MMBTU was assumed to account for short term variability.

**Table 16**  
**Maximum Predicted Air Quality Impacts from the Project at Class I Areas**

Class I Area	Pollutant and Averaging Time					
	NO <sub>x</sub>	SO <sub>2</sub>			PM <sub>10</sub>	
	Annual	3-hour	24-hour	Annual	24-hour	Annual
Arches NP	0.0021	0.720	0.172	0.008	0.062	0.004
Bandelier NM	0.0074	<b>1.268</b>	<b>0.273</b>	0.017	0.092	0.006
Black Canyon of the Gunnison NM	0.0026	0.929	0.180	0.008	0.050	0.003
Canyonlands NP	0.0045	<b>1.479</b>	<b>0.476</b>	0.013	0.184	0.005
Capitol Reef NP	0.0010	0.711	0.159	0.005	0.072	0.002

Grand Canyon NP	0.0003	0.447	0.127	0.002	0.053	0.001
Great Sand Dunes NM	0.0018	0.547	0.147	0.006	0.050	0.002
La Garita WA	0.0028	0.761	0.151	0.007	0.053	0.003
Mesa Verde NP	0.0261	<b>4.706</b>	<b>0.790</b>	0.044	0.263	0.016
Pecos WA	0.0041	0.690	0.190	0.011	0.068	0.004
Petrified Forest NP	0.0008	0.939	<b>0.212</b>	0.004	0.091	0.002
San Pedro Parks WA	0.0169	<b>2.379</b>	<b>0.533</b>	0.030	0.187	0.011
Weminuche WA	0.0086	<b>1.803</b>	<b>0.270</b>	0.017	0.093	0.007
West Elk WA	0.0016	0.722	0.173	0.006	0.049	0.002
Wheeler Peak WA	0.0028	0.727	0.092	0.008	0.046	0.003
<b>Proposed Class I SIL</b>	0.1	1.0	0.2	0.1	0.3	0.2
<b>PSD Class I Increment</b>	2.5	25.0	5.0	2.0	8.0	4.0

Note: Bold values indicate predicted values above the proposed Class I Significant Impact Levels.

### C. NAAQS Compliance

As discussed above in general, to show NAAQS compliance, Sithe performed cumulative analyses for PM<sub>10</sub> and SO<sub>2</sub> by including the emissions of nearby sources. Sithe used data on source allowable emissions from State emission inventories where available, and Sithe supplemented this data by using EPA's National Emissions Inventory (NEI). Sithe used a "distance rule", agreed upon with EPA and the NPS, to simplify the cumulative analyses and allow for reasonable model run times. For SO<sub>2</sub>, if a source's emissions in tons per year are less than 0.8D, where D is distance in km, then it is deemed small enough to omit from the modeling. The 0.8 in the rule was suggested by NPS and is based on past modeling work and experience showing that the impact of such small and distant sources to be negligible. A 40 tpy source would be omitted only if it were 50 km or more away, which illustrates the conservativeness of the distance rule used by Sithe.

The results of the cumulative NAAQS analyses are shown in Table 17 below. The results, including the monitored background concentration, are less than half the NAAQS in every case. Sithe has thus demonstrated compliance with all the NAAQS.



**Table 17**  
**Predicted Cumulative Air Quality Impacts on the NAAQS**

Pollutant	Averaging Period	Modeled Impact (ug/m <sup>3</sup> )	Background Concentrations (ug/m <sup>3</sup> )	Total Impact (ug/m <sup>3</sup> )	NAAQS (ug/m <sup>3</sup> )
SO <sub>2</sub>	3-hour	403.56	6.2	409.7	1300
	24-hour	98.3	6.2	104.5	365
PM10	24-hour	8.55	20	28.5	150
	Annual	1.9	20	21.95	50

Note: For the cumulative analysis, because of the way the NAAQS are defined, the second highest predicted concentration is compared to the NAAQS level. Thus some values in this table may be lower than in Table 15, where the first high is used, to provide a more conservative assessment of whether the Facility has any impacts above the SIL.

#### **D. Increment Consumption Analysis**

The cumulative analysis for PSD increment, which is discussed generally above, is more complicated than the analysis for the NAAQS, because not all emissions "count" toward, or consume, increment. EPA's regulations provide that the only emissions changes that consume increment are those emissions that have occurred since the "baseline date". The reason for this provision is that the PSD program is aimed at the preventing the significant deterioration of the air quality in an area relative to the baseline conditions of that area. In addition, emissions decreases in the same area expand or increase the available increment, because the emissions decreases tend to improve air quality relative to the baseline date of the area.

For the PSD increment analysis, Sithe used State databases for much of the required data. Sithe also used a conservative procedure (i.e. likely to overestimate emissions) to simplify the analysis for major sources. Sithe's procedure assumed that all of the emissions at major sources, with two exceptions discussed below, consumed increment, regardless of when the emissions began to occur relative to the baseline date. PSD increment consumption is based on changes in actual emissions (not maximum allowable emissions), of which records are kept. Continuous Emissions Monitors (CEMs) in the stack of each major source are required under various regulatory programs, such as the Acid Rain Program. EPA, therefore, provided Sithe with nearby sources' maximum actual emission rates that were representative of their normal operation.

In some cases, the PSD increment analysis is more complicated than that needed in this

case. For example, the emissions from minor sources are often omitted or undercounted in State databases. That potential problem is not present for this permitting action because the area surrounding the site of the proposed Facility is sparsely populated, and has relatively little commercial or industrial activity or growth. Therefore, this issue is not of concern for Sithe's Class II increment analysis. For the Class I increments, Sithe agreed to a much larger modeling domain encompassing all Class I areas within 300 km. EPA and Sithe consulted with the State air agencies of the Four Corners States of Arizona, Colorado, New Mexico, and Utah. In each case, based on general knowledge of the areas, minor source permitting programs, and previous studies of the status of the increment, State regulators concluded that minor source growth had a negligible impact on the PSD increment. Thus, EPA has determined that emissions from minor sources and the potential for minor source growth will not have any effect on either the Class II or Class I increment analysis.

A second potentially complicating factor for PSD increment analysis is that the "baseline date" may be different for different areas, because the baseline date is triggered by the issuance of the first major source permit in each area. This means that each source could have different fractions of its emissions count toward increment depending on which Class I area was being evaluated; in the worst case this would require different combinations of emissions estimates and different modeling runs for every Class I area. Sithe, however, handled this issue by applying the conservative procedure mentioned above, which assumes that all emissions at each major source consume increment regardless of baseline date. This procedure is considered conservative because it overestimates potential emissions.

Sithe applied two exceptions to this conservative procedure. The two nearest major sources of emissions to the site of the proposed Facility are the Four Corners Power Plant (FCPP), and the San Juan Generating Station (SJGS). FCPP is 22 km away from the site of the proposed Facility and SJGS is 35 km away. Both FCPP and SJGS have reduced their emissions substantially in the past two decades by installing pollution control equipment and improving operations. The emissions reductions from FCPP and SJGS have expanded the available increment in the area surrounding the site of the proposed Facility, leaving more of the increment available. Although some of the emissions reductions from FCPP and SJGS were required by EPA to remedy SO<sub>2</sub> NAAQS violations monitored in the 1970s, the actual reductions were far greater than required to cure the NAAQS violation.

EPA provided Sithe with the emission rates promulgated in 46 FR 43152-43154 (Aug. 27, 1981) and 46 FR 30653-30654 (June 10, 1981), for FCPP and SJGS that were required for attainment of the SO<sub>2</sub> NAAQS. Sithe then modeled only the emissions reductions from FCPP and SJGS that went beyond those required for NAAQS attainment.

The results of the cumulative PSD increment analysis are shown in the table below. The results, including the monitored background concentration, are well below the Class I and Class II increments where they are respectively applicable. Sithe has thus demonstrated compliance with the PSD increments.

**Table 18**  
**Predicted Cumulative Air Quality Impacts on the Class II Increments**

Pollutant	Averaging Period	Modeled Impact (ug/m <sup>3</sup> )	Increment (ug/m <sup>3</sup> )
SO <sub>2</sub>	3-hour	67.3	512
	24-hour	10.75	91
PM10	24-hour	8.47	30
	Annual	1.82	17

**Table 19**  
**Predicted Cumulative Impacts on the Class I SO<sub>2</sub> Increments**

Class I Area	SO <sub>2</sub> impacts, µg/m <sup>3</sup>		
	3-hour	24-hour	Annual
Bandelier NM	6.76	2.15	0.054
Canyonlands NP	6.76	2.15	0.097
Mesa Verde NP	12.84	2.15	-0.034
Petrified Forest NP	16.38	3.72	0.374
San Pedro Parks WA	2.54	0.90	-0.028
Weminuche WA	3.51	0.45	0.009
<b>PSD Class I Increment</b>	25	5	2

Note: Proposed Facility impacts exceeded the proposed Class I Significant Impact Level only for SO<sub>2</sub>, and only at six Class I areas. Negative numbers indicate increment expansion, due to emission reductions at FCPP and SJGS.

## VIII. ADDITIONAL IMPACT ANALYSIS

In addition to assessing the ambient air quality impacts expected from a proposed new source or modification, the PSD regulations require that certain other impacts be considered. These include impacts on visibility, soils and vegetation, and growth.

## **A. Visibility**

Sithe modeled the proposed Facility's potential impact on visibility and other AQRVs, which are defined by the FLM for each Class I area. As mentioned above, Sithe conducted several rounds of additional modeling, after extensive consultations on modeling procedures with the FLMs.

The "Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report" (USFS, NPS, US F&WS, December, 2000), also known as the "FLAG document" prescribes procedures for assessing impacts on Class I areas. Sithe followed the FLM's recommended procedures for using CALPUFF along with the post-processing program CALPOST, for assessing acid deposition impacts and regional haze impacts. The modeled sulfur and nitrogen deposition were below the FLMs' "Deposition Analysis Thresholds" (DATs) of 0.005 kg/ha (kilograms per hectare). Therefore, the FLMs concluded that further analysis was not required and have not made any finding of adverse impact on AQRVs related to deposition or visibility. For visibility, see page 38 for a discussion of the USFS letter dated April 25, 2006.

At the request of the USFS, Sithe also performed an analysis of the proposed Facility's effect on the acid-neutralizing capacity (ANC) of 10 lakes in four Class I areas. Using the Forest Service screening methodology, which is based on the modeled acid deposition and the lakes' size and rainfall, Sithe showed that the proposed Facility's impacts were below the USFS level of concern.

For assessing regional haze impacts, the FLAG document prescribes a screening procedure based on changes in extinction, which is defined as changes in the attenuation of transmitted light, per unit distance, caused by the proposed Facility project. CALPUFF predictions for sulfate, nitrate, and particulate matter are multiplied by the light extinction capacity of each, then the daily averages of the resulting total extinction increase above natural background is compared to the 5% level. The 5% level of extinction indicates an amount of haze just perceptible to an observer. If the 5% level of extinction is exceeded on any day the FLAG document recommends additional analysis to assess whether there is an adverse impact.

Sithe carried out the FLAG screening procedure and found days over the 5% concern level at 11 of the 15 Class I areas; six areas had at least one day over 10% extinction. Sithe then conducted an additional analysis. The most significant part of this alternative analysis was an examination of individual hours within each daily average, to check for times when visibility was already naturally obscured by rainy or cloudy weather. Sithe concluded that excluding those problematic hours from the averages brings the proposed Facility's emissions impact project back under the 5% level, so that its visibility impacts are acceptable.

Sithe also performed a supplemental analysis to assess the impact of the proposed Facility

on requirements for progress toward natural visibility conditions. Sithe modeled the emission changes at FCPP and SJGS, added the emissions from the proposed Facility and evaluated the change in visibility at Class I areas using the same metric that is used under the Regional Haze Rulemaking (extinction improvement in the best 20% and worst 20% of the days). This modeling showed that visibility would improve in the area regardless of the emissions from the proposed Facility. Sithe's analysis showed that the resulting visibility improvement exceeded the 10% Regional Haze Rulemaking progress requirement through 2010 (based on a six year period, 10% of the way to the final goal in 2064). In addition, Sithe has agreed to perform additional mitigation that will more than offset any potential contribution to visibility impairment.

EPA has concluded that construction and operation of the proposed Facility is consistent with the requirements for visibility improvement under the Regional Haze Rule.

## **B. Soils and Vegetation**

The PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, and sensitive types of soil. Evaluation of impacts on sensitive vegetation were performed by comparing the predicted impacts attributable to the project with the screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (EPA 1980).

The modelling analysis showed all impacts to be well below the screening levels. Most of the designated vegetation screening levels are equivalent to or less stringent than the NAAQS and/or PSD increments, therefore satisfaction of NAAQS and PSD increments assures that sensitive vegetation will not be negatively affected.

## **C. Growth**

Growth impacts due to the proposed project are not expected to be significant. There will be little new growth in the area due to the small work force (200-225 employees) expected during plant operation. The emissions associated with the workforce will be primarily the result of motor vehicle exhaust emissions associated with the commute of workers to and from the plant site.

## **IX ENDANGERED SPECIES**

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. § 1536, and its implementing regulations at 50 C.F.R. Part 402, EPA is required to ensure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. EPA has determined that this PSD permitting action triggers ESA Section 7 consultation requirements. EPA is therefore required to consult with the U.S. Fish and Wildlife Service (FWS) and/or the National

Marine Fisheries Service (NMFS) if an endangered species or threatened species may be present in the area affected by the permit project and EPA's action (i.e., permit issuance) may affect such species. EPA is also required to confer with the Services on any action which is likely to jeopardize the continued existence of any species proposed for listing (as endangered or threatened) or result in the destruction or adverse modification of habitat proposed to be designated as critical for such species.

When a Federal action involves more than one agency, consultation and conference responsibilities may be fulfilled through a lead agency pursuant to 50 CFR § 402.07. Since the land, electrical transmission lines, and access roads required for the proposed project are located on the Navajo Indian Reservation and lands under the jurisdiction of the Bureau of Indian Affairs (BIA), the BIA will act as the lead Federal agency for purposes of fulfilling the responsibilities under Section 7 of the ESA for the project.

EPA may proceed with the final permit issuance upon conclusion of consultation, review of FWS's Biological Opinion, and our determination that issuance of the permit will be consistent with the ESA requirements.

#### **X. NATIONAL HISTORIC PRESERVATION ACT (NHPA)**

Section 106 of the NHPA requires responsible Federal officials to take into account the effects of their decisions on historic properties eligible for the National Register of Historic Places, and consult with appropriate State or Tribal Historic Preservation Officers and other interested parties to avoid, reduce, or mitigate any identified adverse effects. The applicant has retained a consultant to conduct cultural resource studies to support Section 106 consultations. On 17 February 2004, the consultant contacted the Navajo Nation Tribal Historic Preservation Officer (THPO) to provide initial notification about the proposed Facility, inform him of the purpose of the project, and briefly describe the elements of the project. As a follow up to the initial contact, the applicant is prepared to work with the BIA in consulting with the Navajo Nation THPO about defining the area of potential effect, identifying other potentially interested parties who should be involved in the consultations, and developing an appropriate strategy to inventory and evaluate cultural resources that could be affected.

#### **XI. TITLE IV (ACID RAIN PERMIT)**

The applicant must apply for and obtain an acid rain permit. The applicant will apply for this permit prior to facility operation.

#### **XII. ENVIRONMENTAL JUSTICE**

On February 11, 1994, Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," was signed. EPA defines environmental justice as the fair treatment and meaningful involvement of all people

regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA has this goal for all communities and persons across this Nation. In addition, EPA published guidance entitled, “Final Guidance For Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses” in April 1998.

With respect to the proposed Facility, EPA is aware that the public is raising environmental justice concerns in the NEPA process. Please see our June 15, 2005 letter which reflects our comments on the May 2005 Draft Summary Scoping Report for the Desert Rock Energy Project. In this letter, we note that the public has identified five issues of concern. These issues are:

- 1) Lack of jobs provided to people of Navajo Nation,
- 2) Social impacts,
- 3) Use of local water sources as disproportionately damaging to local communities,
- 4) Disproportionate exposure to pollutants, potential health problems (respiratory, heavy metals in fish), and
- 5) Impacts without benefits: power goes to other locations and is not distributed locally.

In response to the concerns listed above, EPA is conducting additional outreach on the PSD aspects of the proposed Facility in the form of workshops with Dine translators, radio announcements in Dine, and translations of fact sheets in Dine. The applicant has also prepared a data presentation to better characterize the issues raised in the NEPA scoping effort regarding environmental justice and EPA expects that these issues will be addressed through the NEPA process.

### **XIII. CONCLUSION AND PROPOSED ACTION**

Based on the information supplied by Sithe, our review of the analyses contained in the permit application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed Facility will employ BACT and will not cause or contribute to a violation of the NAAQS, or an exceedance of PSD increments. Therefore, EPA is proposing to issue Sithe a PSD permit for the Facility, subject to the PSD permit conditions specified herein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period and upon completion of the ESA consultation process.

